Natural Gas Week

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Late News...

Global coup. International Energy Agency (IEA) reiterates that barring implementation of new environmental policies to restrict carbon emissions, global natural gas demand will grow by 2.6% annually through 2020. If new policies are put in place, growth could be even greater.

* * *

Takes one to know... Phillip R. Sharp, who headed up Energy Department's Electricity Reliability Task Force, tells conference in Annapolis, Md., that only in Washington "would they put a politician anywhere near something called reliability." A former Democratic congressman from Indiana, Sharp now lectures at Harvard.

* * *

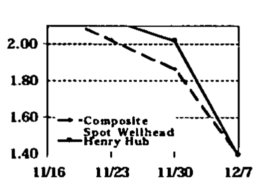
He's baaaack. Newly appointed GOPers on the panel recommend Sen. Frank H. Murkowski be chosen for third term as chairman of Senate Energy and Natural Resources Committee. Nod must be ratified by Republican Conference next month. New lawmakers added to panel — Jim Bunning, R-Ky.; Peter G. Fitzgerald, R-Ill.; Evan Bayh, D-Ind.; and Blanche Lambert Lincoln, D-Ark.

* * *

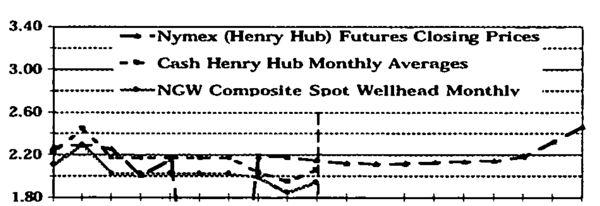
Fat chance. Branko Terzic, former member of FERC and ex-CEO of Yankee Energy Services, says of FERC proposals to liberalize secondary market at Washington conference: "I think you have a better chance of estimating rates in a market dynamic than you have of estimating what a future FERC would do."

* * *

Average Cash Prices & Futures Strip



Prices declined drastically following a stronger-than-November bid-week, and a continued soft market is expected this week.



Henry Hub Gas Falls Below $1 As Producers Hope for Frost

With every near-term factor in the natural gas market currently bearish — including plummeting oil prices quashing most opportunities for fuel switching to gas — producers now must pin all hope for rising prices on some sustained and seasonal winter weather arriving soon.

A number of bearish factors have converged. Mild weather, a large surplus of working gas in storage as compared to years past, pipelines restricting flows onto their systems due to bloated linepacks (see story, p.3), and the prospect for further increases in the storage surplus have brought about comparisons to the winter of 1994-95 when a similar situa-

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Gas-Thirsty Southeast States Wait for New Pipeline Projects

While Florida is poised for an imminent boom in natural gas demand, the rest of the U.S. Southeast — with its burgeoning populations and fast-rising economies — may not be far behind in developing new gas markets.

Reacting to likely gas supply constraints in the state, the Williams Companies Inc.'s TransContinental Gas Pipe Line Corp. (Transco) is developing a new Florida pipeline system, dubbed the Buccaneer Pipeline (see story, p.16). Industry sources have speculated that the line would need around 500 MMcfd of capacity to be feasible (NGW, 10-26-98, p.5).

Florida Gas Transmission Co. (FGT) — which controls

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Pairing of 2 Big Oil Companies Also Forms Global Gas Gorilla

The pending $75 billion merger of Exxon Corp. and Mobil Corp. has generated a spate of superlatives in describing its magnitude, but somewhat overlooked so far is where the new combination ranks in the global hierarchy of natural gas players.

Mobil already is big, with global gas reserves of 17 Tcf. Exxon is gargantuan, holding some 42 Tcf. Together they create the largest privately owned gas company in the world and the only nongovernment-owned company among the top 15 reserves owners.

Already, both are major participants in North America,

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Published by Energy Intelligence Group

Perspective

Exxon and Mobil Shake Hands As the Industry Gasps Aloud

Principals in the $80 billion takeover of Mobil Corp. by Exxon Corp. would shrink from the comparison, but a persuasive argument can be made that the mega-deal that rocked the petroleum industry last week is the most major defining event for Big Oil since the *Exxon Valdez* ran aground off Alaska in 1989.

There is little doubt that that environmental disaster nearly a decade ago changed the rules of the game for Big Oil. That mammoth oil spill splashed all over the public perception of the petroleum industry, marking it in the eyes of many as the global despoiler. The Alaskan oil spill remains the single biggest reason for the continuation of offshore drilling moratoria imposed by President Bush.

It isn't simply the size of the Exxon-Mobil deal that makes it so remarkable, although it is mammoth and had energy journalists last week scrambling for their thesauruses, in search of synonyms for big. Nor is it necessarily that Exxon's takeover of Mobil represents a reuniting of the two most significant entities that emerged from the Standard Oil Trust breakup in 1911, although the irony is striking.

The Exxon-Mobil pairing isn't even a seminal event — British Petroleum plc's $48 billion acquisition of Amoco Corp. is pending review by both the Federal Trade Commission and the European Commission.

What makes Exxon-Mobil a defining event is that it represents incontrovertible confirmation that Big Oil's landscape is changing — BP and Amoco wasn't a fluke — to a sector in which a few colossal companies will be able to do the deals and make the profits in an environment dominated by crushingly low oil prices.

The natural gas implications of the Exxon-Mobil pairing are considerable (see story, p.1). The merger will result in the new company emerging as the dominant gas player in the Pacific Rim. The merger also puts a potentially interesting twist in how Big Oil responds to environmental concerns, and in particular, to the global warming issue, in which gas has a ponderous stake.

Some fissures in Big Oil's solid front against environmentally driven inroads appeared to be developing into even bigger cracks with BP's emergence as an environmentally conscious company. The consensus was that those who would seek cooperative solutions with environmentalists grew stronger as a result of the BP-Amoco deal.

Exxon Chairman Lee R. Raymond, on the other hand, has been an opponent of efforts to limit carbon dioxide emissions, and a foe of global warming zealots, consistently questioning the science as well as the motivations of the loudest green doomsayers. As chairman, CEO and president of Exxon Mobil, Raymond would bring even more clout to his side in the global warming debate.

Nobody left as the winner in the *Exxon Valdez* debacle. One suspects in this case there will be winners, albeit just a few and of gigantic proportions.

—**Michael K. Zastudil**

Henry...

(continued from page 1)

tion weighed heavily on prices throughout 1995.

That year, the storage surplus as compared to the year before increased throughout the winter to top out at 472 Bcf on Feb. 3, 1995. Prices at the wellhead went on to average $1.45/MMBtu for that year.

Prices at the Henry Hub fell last week below the $1/MMBtu level by Friday, more than $1 less than December bid-week prices. Bid-week prices declined throughout, but still came in higher than November's bid-week.

While prices at the New York Mercantile Exchange (Nymex) for January gas are still around the $1.90-$2/MMBtu level — a far cry from the $1.65/MMBtu close of the January 1995 contract — that is still nearly 25¢ lower than when January became the near-month on Nov. 25.

Though producers can find some hope in current weather forecasts, which call for more seasonal temperatures to arrive in some areas this week, the near-term for prices will still be ugly.

Last week, several producers said that current prices were too low to sell their gas, but most talk of shut-ins is extremely preliminary.

"Our problem is, these prices are lower than the price at which we injected gas," said one Houston-based trader. "People have to withdraw their storage gas, and there's nowhere for it to go."

Though many local distribution companies (LDCs) must stick to fairly inflexible storage injection/withdrawal schedules and are currently in the midst of the traditional withdrawal season, the American Gas Association (AGA) said that during the week ending Nov. 27 a total of 8 Bcf was *injected* into U.S. underground natural gas storage facilities.

The eastern consuming region — where many strategic LDCs are located — did report a net withdrawal of 7 Bcf, but both the western consuming region and producing region reported net injections.

AGA said that stocks currently stand at 3,077 Bcf, or 95% full, and at that level there is 471 Bcf more in storage than at the same time last year. That's the equivalent of nearly eight days of total U.S. gas consumption.

That surplus should grow this week, and possibly the following week, as the comparable withdrawals for those weeks last year were 69 Bcf and 136 Bcf, respectively. By Dec. 11, the surplus will likely be more than 500 Bcf, with the total amount of working gas in storage likely higher than 2,950 Bcf. Little cold weather is expected to arrive prior to that time.

Omaha, Neb.-based Strategic Weather Services (SWS) said that colder weather will arrive Dec. 11-15.

"This will bring very cold conditions to the eastern two-thirds of the nation, which will be the first major cold outbreak of the season," SWS said. "At the same time, mild weather will dominate the West Coast."

Though this news should give some optimism to producers about price increases during that period, the expansion of the Northern Border Pipeline Co. system is expected to come on line around the same time and bring increased incremental Canadian gas supplies into the U.S. Midwest.

But there are some intermediate- and long-term fundamental factors that 0should quiet talk of a repeat of 1995.

Simmons & Co. International said that Gulf of Mexico well de-

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pletion rates are increasing rapidly creating a necessity for increased drilling to sustain current deliverability, and the increased demand predicted for the years to come (see story, p.4).

Also, the Colorado State University hurricane forecast team said that the June 1-Nov. 30, 1999 hurricane season will be as active as the one that just ended, with 14 named storms, nine hurricanes and four intense hurricanes to form in the Atlantic Basin.

—**Scott C. Speaker**

Flood of Gas, Little Demand Prompt Pipelines to Issue OFOs

Too little demand in the East Coast consuming regions and too much supply coming out of the producing areas has forced several major interstate pipelines to issue operational flow orders (OFO) requiring that receipts into their systems match deliveries off the pipeline.

Texas Eastern Transmission Co. (Tetco) cannot absorb any more gas than customers take for consumption, said Richard Kruse, vice president and general counsel. Tetco is a unit of Duke Energy Corp. Consequently, the company issued a system-wide OFO.

"Because of the lack of cold weather, storage is full, and linepack is at the maximum," Kruse told *Natural Gas Week*. The OFO was scheduled to go into effect at 9 a.m. CST on Saturday.

An OFO was to become effective at the same time on the Tennessee Gas Pipeline system.

"Our pipeline and storage are packed to the rafters," said Paula Delaney, spokeswoman for El Paso Energy Corp., Tennessee's parent.

For producers and other shippers, their options are limited to shutting in gas or finding another market. "For us the issue is 'just put in what you can take out'," said Bin Halverson, general manager of marketing for Duke's northeastern pipelines group.

Tetco said supply on its system was exceeding demand by about 200 MMcfd to 250 MMcfd. The pipeline had issued alerts and informal requests to reduce deliveries to keep the system in balance, but by Thursday night, the company determined that formal action had to be taken.

"We very reluctantly issued the operational flow order," Kruse said. "It was our first in more than a year."

Penalties for failing to comply with the OFO should provide an adequate incentive to shippers. The fee on the Tetco system is $25/Dth, to be assessed daily. If a shipper, say a large marketer, is out of balance by 1 MMcfd, the penalty would be $25,000 for each day of non-compliance.

Tennessee will charge violators $15/Dth, plus other charges.

The Tetco system runs from South Texas and the Gulf of Mexico, through Louisiana, Mississippi, Tennessee, Kentucky, Pennsylvania, New Jersey and into New York City.

The Tennessee system extends from the Gulf Coast-Gulf of Mexico to Boston.

Other pipeline companies said they are monitoring their systems closely and have alerted shippers to potential problems, particularly as industrial demand drops off over the weekend.

ANR Pipeline Co., a subsidiary of the Coastal Corp., has been operating on "critical" status since Dec. 2, spokesman Joe Martucci said. Interruptible customers of ANR Storage Co. are no longer allowed to inject volumes into storage facilities.

The ANR system runs from the Midcontinent and Gulf of Mexico to Michigan and the Upper Midwest.

Southern Natural Gas Co., the pipeline unit of Sonat Inc., also was operating on "critical" status. "There's a lot of supply, and it's more than we can handle. We are trying to work within the limits of the system," spokesman Bruce Connery said.

Transcontinental Gas Pipeline Co., a subsidiary of the Williams Companies Inc., had "alerted" customers to monitor their receipts and deliveries.

Strong gas prices are one cause of the excess supply situation. Even though prices are well below year-ago levels, 30-day and longer-term gas remain above the producers' break-even threshold.

The cash market for day-to-day and shorter-term deals is much lower, around $1-$1.25/Mcf, but very small volumes are flowing at these prices.

—**Barbara Shook**

Inside This Issue...

Depletion Rate for Gulf Gas Headed for 50%, Study Shows

Natural gas reserves in the Gulf of Mexico are being depleted at an eye-popping annual average rate of 38%, which will escalate to nearly 50% within the next three years, said officials at Houston-based Simmons & Co. International.

"About 80% of all gas now produced from the outer continental shelf (OCS) comes from wells drilled since 1991. That tells us that if we want to keep production at current levels, we've got to keep drilling in the Gulf," said David A. Pursell, vice president of Simmons & Co. Pursell authored a study of gas and oil depletion in those federal waters that apparently is the first of its kind.

Depletion of current Gulf gas reserves is expected to total 4.1 Bcfd in 1999. That means offshore operators will have to successfully complete about 1,000 wells in those waters next year to maintain current production.

The Gulf — particularly the mature producing area in the shallower shelf waters offshore Texas and Louisiana — is the "backbone of the U.S. oil and gas supply base." Gas production from offshore leases in the Gulf now totals nearly 14 Bcfd, or 27% of total U.S. gas production of 52 Bcfd. The Gulf also accounts for 15%-20% of total domestic oil production, said Pursell.

The shelf areas offshore Texas and Louisiana contribute 84% of the Gulf's total gas production, with the other 16% coming from the shelf area east of Louisiana and water depths greater than 250 meters, or 820 feet.

At the start of this year, the 2,300 gas wells on the Louisiana shelf were producing a total 7.19 Bcfd of gas, 160,000 b/d of condensate and 360,000 b/d of water. Another 800 wells on the Texas shelf were producing 2.68 Bcfd of gas, 60,000 b/d of condensate and 85,000 b/d of water. The rest of the federal Gulf waters included 200 wells producing 1.88 Bcfd of gas, 35,000 b/d of condensate and 25,000 b/d of water.

Most Gulf reservoirs produce through strong water-drive. As pressure drops in the oil or gas reservoir, the aquifer expands into areas previously occupied by hydrocarbons and eventually migrates into producing wells.

Existing oil reserves in the Gulf are being depleted at an average annual rate of 26%, which is expected to increase into the low 30 percentile in three years, Pursell said.

Researchers at Simmons & Co. used benchmark industry data to chart monthly production figures of every completed well in the federal waters of the Gulf during 13 two-year segments from 1970 through 1996, the latest period for which full data are available.

Depletion Rates Took Sharp Jump

They found gas wells drilled in the Gulf during 1996 are depleting at much faster rates than those drilled in 1970-71. Depletion rates averaged less than 20% annually until the mid-1980s when depletion rates from new wells begin to escalate rapidly to nearly 50% annually.

Depletion of fields often is masked by the drilling of new development wells or by workovers and stimulations of existing wells to increase production, Pursell said.

Yet despite the 1979-81 drilling boom and the more recent spurt in offshore drilling activity from 1996 through early 1998, the rate of production declines on the Louisiana shelf has increased exponentially to 49% through the first quarter of this year from 17% in 1970-71.

The average annual depletion rate among oil wells on federal leases in the Gulf remained around 20% until the early 1990s when it began increasing steadily to more than 33% among new wells. The composite oil depletion rate in the Gulf is now about 26%, officials said.

At current rates of depletion, the industry will have to

(continued on page 5)

SALT CAVERN STORAGE
(Billion Cubic Feet)

Facility	State	MMcfd Max Injection	MMcfd Max Withdraw	Nov 27 Bcf Capacity	Nov 27 Bcf Working	% Full	Bcf Chng Weekly	Bcf Chng From 1st	Nov 1 Bcf Capacity	Nov 1 Bcf Working	% Full
Bethel Lone Star	Tex.	132	600	NA	NA	NA	NA	NA	NA	NA	NA
Hattiesburg Hattiesburg	Miss.	175	350	5.5	4.1	75%	0.0	0.0	5.5	4.1	75%
Moss Bluff Tejas	Tex.	450	900	10.3	9.6	93%	0.2	0.3	10.3	9.3	90%
North Dayton HNG Storage	Tex.	250	500	6.3	3.1	49%	0.7	-0.8	6.3	3.9	62%
Petal Crystal Oil Co.	Miss.	160	320	3.2	2.5	78%	0.1	0.0	3.2	2.5	78%
Stratton Ridge Tejas Ship Channel LLC	Tex.	80	250	2.0	0.9	43%	-0.1	-0.4	2.0	1.2	62%
Stratton Ridge KN Energy	Tex.	50	100	6.8	2.4	36%	0.0	0.3	6.8	2.2	32%
Wilson Storage Valero	Tex.	360	800	7.2	6.3	88%	0.5	0.2	7.2	6.1	85%
Yaggy Mid-Con. Mkt. Ctr.	Kan.	190	190	2.9	2.8	97%	0.1	0.0	2.9	2.8	97%
Total:		**1,847**	**4,010**	**44.2**	**31.7**	**72%**	**1.4**	**-0.4**	**44.2**	**32.1**	**73%**

NOTES: (1) *Max Injection* is the maximum amount of gas that can be injected into the facility in one day. (2) *Max Withdrawal* is the maximum amount of gas that can be withdrawn in one day. (3) *Capacity* is the maximum amount of working gas that can be stored in the facility. (4) *Working Gas* is the gas in the facility that can be withdrawn. (5) *% Full* is the amount of working gas in storage as a percentage of capacity. (6) *Bcf Change Weekly* is the amount of difference in billions of cubic feet between the current working gas levels reported and the working gas levels reported in the previous survey. (7) *Bcf Change From 1st* is the amount of difference in billions of cubic feet between current working gas levels and working gas levels reported on the first day of the month. *Sabine Pipe Line Co. recently opened its second Spindletop salt cavern — increasing working gas capacity at the site by 6 Bcf.

(continued from page 4)
complete almost 1,000 new gas and oil wells in the Gulf next year just to maintain present production levels. By 2001, the number of successful completions needed will escalate to more than 1,150, Pursell said.

By comparison, the industry has averaged about 940 successful completions in the Gulf each year during the 1990s, officials said.

U.S. gas demand has grown at an annual rate of 2% since 1989. "On a base demand of approximately 58 Bcfd, this equates to over 1 Bcfd of additional natural gas productive capacity every year to meet growing demand," said Simmons officials.

The additional gas supplies required both to satisfy growing demand and to offset the escalating depletion of Gulf shelf reserves will likely have to come from deep-water and subsalt operations in the Gulf or from western Canada, they said.

Dayrates for jackup rigs in the Gulf have tumbled to the low $20,000s from a peak of $70,000 earlier this year. The number of jackups stacked in the Gulf has jumped to 25 from zero in six months, while rig utilization in those waters tumbled to 76% from 97% previously.

—Sam Fletcher

Vickrey Auction Plan Advanced As Framework for Gas Pipelines

Most people have never heard of the Vickrey auction model, but it's being floated as a way to set the reserve, or floor, price for short-term capacity on natural gas pipelines.

In a meeting last week with staff members of the Federal Energy Regulatory Commission (FERC), a proposal was advanced by Stuart C. Maudlin, president of Sabre Energy Network, that addressed setting reserve prices — the main sticking point of the short-term capacity Notice of Proposed Rulemaking (NOPR) (NGW, 8-3-98, p.4).

Since the NOPR was issued earlier this year, concern has been widespread regarding the setting of a reserve price, especially in low-demand periods. Would regulators or pipeline companies set the reserve price? Or is there some other mechanism that can set the price?

Under the Vickrey — named for William Vickrey, Nobel Prize-winning economist in 1996 — auction model, which is more commonly known as the uniform second-price auction, bids are sealed and each bidder is unaware of the other bids. In the case of short-term capacity auctions, Maudlin proposes selling all capacity at the lowest winning bidder price until all available capacity is sold, or until the next lower bid, if awarded, would lower the total value of capacity sold.

For example, in a low-demand period a shipper may bid 10¢/Mcf to ship 100 Mcf of gas, worth $10. A second bid for 9¢/Mcf to ship 100 Mcf would push the reserve price value to $18 (100 Mcf + 100 Mcf * 9¢).

The next bid for 5¢/Mcf to ship 100 Mcf would be rejected, however, as its value of $15 (100 Mcf + 100 Mcf + 100 Mcf * 5¢) falls below the previous bid. The reserve price would thus be 9¢/Mcf.

All bidders would pay the same rate for the same capacity, and no bidder pays more than its "reserve" ceiling. Under this approach, bidders also avoid the "winner's curse" — paying more for the capacity than its value.

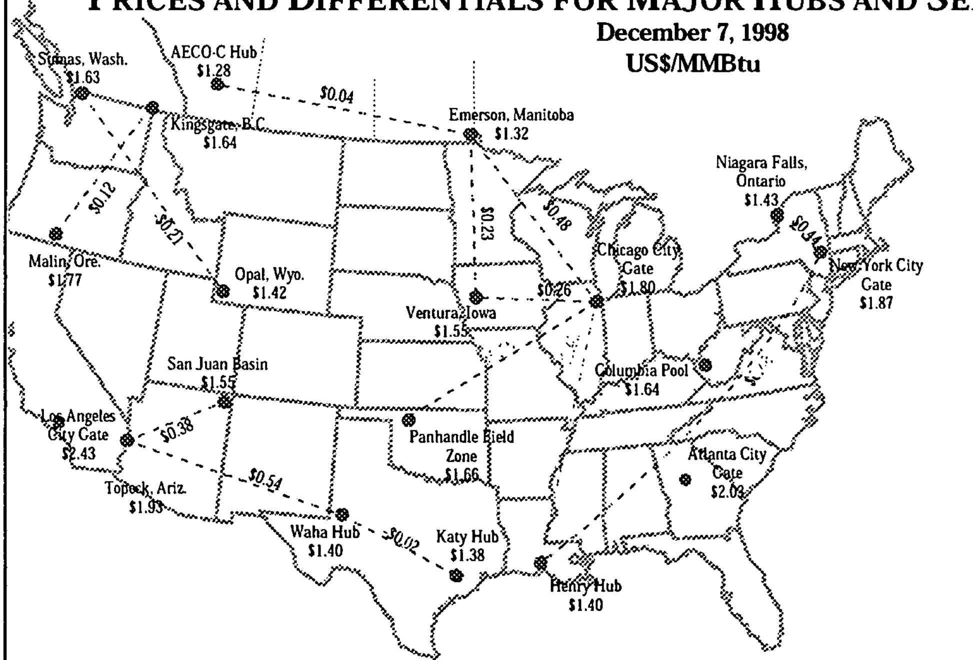
FERC's NOPR has come under fire from many sectors of the natural gas industry. For short-term capacity — defined as terms of two days to one year — the market would bid on a shipping price. But the pipeline would not be required to accept any bid below the reserve price, thus setting a price floor with no price ceiling, to the shipper's detriment.

Under the proposed daily auctions, however, FERC would (continued on page 6)

PRICES AND DIFFERENTIALS FOR MAJOR HUBS AND SELECTED CITY GATES

December 7, 1998

US$/MMBtu



NOTES:

(1) Sumas, Wash.; Kingsgate, B.C.; Emerson, Manitoba; and Niagara Falls, Ontario, are reported as major import points from Canada.

(2) City Gate represents the cost of gas at the point at which the city's local distribution company takes title to the gas, except in Los Angeles where end-users take title to gas delivered on Southern California Gas Co.'s extensive, interstate pipeline-sized distribution system, which reaches eastward, for example, to the state border with Arizona (at Topock, Ariz.).

(3) Malin, Ore., is the point at which Pacific Gas Transmission Co. delivers gas into Pacific Gas & Electric Co.'s Line 400.

(4) All prices are volume-weighted.

(5) Differentials reflect the price difference between the two points, and could be used to represent pipeline transportation costs.

Vickrey...

(continued from page 5)

not mandate a reserve price. This facet has pipelines on edge, as there would be no price floor during low-demand periods.

Maudlin's idea would go one step further than FERC's proposal, using the uniform second-price auction to set the reserve price in both short-term and daily capacity auctions. The reserve price calculation sets the floor price, he said.

Built into Maudlin's uniform second-price auction is a mechanism for those who must have capacity to get it. Bidders would be permitted to submit at-market bids, he said.

Any auction result is distorted if buyers collude, Maudlin said. If all parties agree to "low-ball bid," he added, the results are skewed. However, under the uniform second-price auction model, if any one of the parties deviates, the others lose out and may not get capacity at all.

Because the market — not the pipeline companies — would set the reserve price, the proposal also addresses FERC's concern that pipeline companies would keep capacity off the market by setting an unrealistic reserve price, Maudlin said.

Of the groups affected by the auction process, Maudlin said, "I think the pipes will look at this with appropriately skeptical eyes."

Greg Lander, president of TransCapacity, said the auction proposal seems to respond to the pipeline companies' desire to maximize revenue, and it also addresses FERC's and the market's desire not to pay more than necessary to get capacity.

However, he said there are issues within the proposal that need to be addressed. For example, he asked, what if all bidders submit at-market bids? "Will [the proposal] hold up to the rigors of the what ifs?"

FERC has scheduled a technical conference on the auction proposal for Dec. 8 in Washington. Initial comments on the NOPR are due Jan. 22, 1999.

—Jeff Gosmano

Coalbed Methane Production Up; Low Oil Prices Spur Interest

When Wyoming Interstate Company Ltd. (WIC) filed last week with the Federal Energy Regulatory Commission for approval to construct the $80.5 million Medicine Bow Lateral, it underscored the recognition of coalbed methane as a major new natural gas supply source.

Drilling for coalbed methane has increased significantly in recent months, spurred on by a variety of unrelated factors including low oil prices.

Most industry officials agree that with oil prices below year-ago levels, coalbed methane drilling makes economic sense in today's environment.

"Independents are looking more at natural gas in general because of [low] oil prices," said John Kelso, manager of investor relations for Evergreen Resources Inc., a Denver-based company that drills exclusively for coalbed methane in southern Colorado's Raton Basin.

Coalbed methane drilling is attractive to independents, in particular, because drillsites are small and drilling costs are lower than conventional, deep exploratory wells. One analyst estimates that a coalbed methane well can be drilled for less than $100,000.

Methane is formed in coal seams as part of the process that creates coal. The Energy Information Administration estimates that coalbed methane reserves continued to grow faster than conventional natural gas reserves, accounting for about 7% of year-end 1997 proved gas reserves. Coalbed methane production, which is now more than 5% of the U.S. total, also increased faster.

Similar to the rise in deep-water exploration, where operators now understand how to efficiently drill, complete and produce a well, the same trend is occurring in coalbed methane drilling. For example, Evergreen doesn't drill its wells using traditional methods. The company uses "air drilling," a method of rotary drilling that uses compressed air instead of conventional drilling muds.

In addition, because the Raton Basin consists of low-pressure reservoirs, the company uses larger than average pipe to efficiently transport the gas.

"More operators are figuring it out," Kelso said.

Over time, the industry has unlocked the best way to uncover coalbed methane, said Ron Wirth, director of investor relations for Western Gas Resources Inc.

He agrees that the current low-price environment for oil makes drilling for gas more attractive. However, the process of generating a productive coalbed methane prospect can't be accomplished by quickly drilling a few wells. In many cases, it takes dozens of shallow wells in a project area to produce profitable results.

Coalbed Methane Big in Alabama

Dennis Lathem, executive director of the Coalbed Methane Association of Alabama, said coalbed methane gas accounts for 26% of Alabama's overall natural gas production. Production of this "nonconventional fuel" continues to rise in Alabama, he said, because operators have "gotten a handle on costs and technology to drill these wells."

He added, "Companies have really concentrated on being as efficient as possible."

Coalbed methane drillers also have been getting support from two other sources: the federal government and the Environmental Protection Agency (EPA).

In late October, a law was passed that freed up acreage in the Powder River Basin. Certain rights to coalbed methane were placed in question as the result of a case involving the Southern Ute Indian tribe and Amoco Production Co.

Western Gas and Barrett Resources Corp., exploration

(continued on page 7)

Major Market Prices
December 7, 1998
($/MMBtu)

	This Week	Weekly Change	Bid Week for December
Chicago City Gate	1.80	-0.25	2.27
New York City Gate	1.87	-0.33	2.25
Houston Ship Channel	1.73	-0.27	2.03

NOTES: (1) Chicago City Gate prices are for gas delivered via interstate pipelines to Chicago's local distribution companies. (2) New York City Gate prices are for gas delivered to local distribution companies in New York City via interstate pipelines. (3) Houston Ship Channel prices are for gas delivered to the Houston Ship Channel. All prices are volume-weighted.

(continued from page 6)
partners in the Powder River Basin, put drilling plans on hold waiting for the case to be settled. The companies recently resumed drilling operations and expect to drill an additional 70 coalbed methane wells in 1998 and approximately 500 wells in 1999. Gross production volumes from the play are expected to reach 80 MMcfd by year-end.

The EPA also promotes recovery of coalbed methane gas as a way to keep the gas from entering the atmosphere. The agency's Coalbed Methane Outreach Program encourages coal mines to recover and use or sell coal mine methane, which is naturally released from the coal seams during the mining process.

The program is part of the U.S. Climate Change Action Plan, which outlines a set of voluntary actions designed to reduce the country's greenhouse gas emissions to 1990 levels by 2000.

As of 1998, coal mine methane use in the United States totaled approximately 50 Bcf/year. In terms of greenhouse gas emissions, the EPA said this is equivalent to removing approximately 4.45 million cars from the road.

WIC, the Rocky Mountain affiliate of Coastal Corp., said the new Medicine Bow Lateral, a 24-inch diameter, 143-mile pipeline, would receive coalbed methane from pipeline systems near Glenrock, Wyo., and flow it to WIC's mainline, west of Cheyenne, Wyo.

It is expected to be in service by Jan. 1, 2000, the company said.

—Jeff Gosmano

Water and Natural Gas Can Mix, Enron Chief Tells Conference

Electricity restructuring may be at the forefront of many company strategies these days, but it's water that has captured much of Enron Corp.'s attention.

Earlier this year, Enron bought Wessex Water plc in southwestern England as a way of gaining technical knowledge about the water industry. Although Wessex is a small water company by England's standards, it's larger than any U.S. water company. Enron used its purchase of Wessex as "an ideal platform" to create Azurix, the name Enron chose for its new water company (NGW, 9-28-98, p.2).

"I tried Lay's Water Works, but I lost," said Kenneth L. Lay, chairman and CEO of Enron.

Water is a critical and growing $300 billion/year industry "which is in desperate need of restructuring, privitization and application of sound business practices, all of which are basically lacking...around the world today" said Lay at an Energy Daily conference last week in Annapolis, Md.

In some areas, "the scarcity of water resources has become the limiting factor for both economic and social development," he said.

Wiser use of water resources will be key and will "require significant new investments" of about $600 billion between now and 2010, according to the World Bank, Lay said. "This will only be available if many of the water systems around the world are privatized."

Public water utilities don't have enough capital and are behind in keeping up with today's infrastructure needs. But "privatization is beginning to happen with a vengeance," and that's what prompted Enron to get into the business.

U.S. Water Opportunities Abound

A major part of the water business is pipelines that flow water and waste water. The energy costs associated with these pipelines equal about 30% of the operating costs of the water business and "any significant reduction in energy costs...results in significant improvements and efficiencies, and of course margins, throughout the business chain," Lay said.

Privately owned and operated water companies are much more efficient than publicly owned water companies at maintaining the integrity of a water system, he said.

So why Enron and water?

"We think it's a very favorable time for third-party investments in modernization. There are many international projects that'll become available in the very near future and we think we can play off of our successful commercialization of other formerly public utility markets around the world."

"Government-dominated and highly regulated industries for us create opportunities...and there's a lot of room for creativity" our there, Lay said. After studying the water industry, Enron concluded that "the same skill sets that are needed in the water business" are needed in the natural gas and electric business.

"It's basically just transferring a skill set," he said.

—Victoria K. Green

Trading of Gas on the Internet Roadhog on Information Highway

Energy trading is quickly swamping the Internet with natural gas commodity trading alone accounting to 25% of that total, according to Benjamin Schlesinger, president of Bethesda, Md.-based Schlesinger and Associates.

Schlesinger said the $500 billion gas market is only going to get larger as more gas is traded on the information superhighway.

Unfortunately, however, "the information, software and

(continued on page 8)

1998 Gas Price Outlook

December 7/Week 49

Wellhead	Delivered-to-Pipeline
$1.99	$2.10

NOTES: (1) Prices are in $/MMBtu and are for the calendar year. The cash-price component comes from volume-weighted averages. (2) The **Delivered-to-Pipeline Outlook** price is based on *Natural Gas Week's* monthly and weekly composite spot delivered-to-pipeline prices (published the first Monday of each month) for historical prices; the natural gas futures current month closing price; and each Friday's futures settlement prices for whatever months remain in the year. (3) The **Wellhead Outlook** price is constructed similarly, using monthly and weekly composite spot wellhead prices for past months and weeks, plus futures-contract prices for the out months, minus a historical differential (13¢) between delivered-to-Henry Hub prices and wellhead prices as published in *Natural Gas Week*. (4) Futures prices are provided by the New York Mercantile Exchange and published weekly in this newsletter.

12-Month Natural Gas Futures Strip

NYMEX	KCBT
$2.078	1.983

NOTES: The "12-Month Natural Gas Futures Strip" is a simple average of one year's worth of futures settlement prices. The average price indicated is based on Friday afternoon closing prices for the next 12 contract months.

Trading...

(continued from page 7)
communications technologies are really severely strained in this business... Technology improvements are needed fast," he said last week at a conference sponsored by Energy Daily in Annapolis, Md.

Much of the increased Internet trading occurs among marketers — there are 300 gas marketers and 100 active power marketers today in the United States and Canada, Schlesinger said.

"Half of the gas that gas marketers buy they buy from other gas marketers. The other half is from producers," he added. If you look at title transfers on the New York Mercantile Exchange (Nymex), this year alone they'll amount to $380 billion in just natural gas futures contracts. "And that excludes the basis market and the over-the-counter futures market" which supplements Nymex trading, Schlesinger said.

Adding to the greater Internet traffic are cross-media deals that combine electricity and natural gas trading. "There are as many versions of cross-media deals as there are marketers" and these deals are often very complicated, Schlesinger said.

As an example of a cross-media deal, Schlesinger said that if a marketer briefly leases the capacity from two power plants — "I take capacity so that I'm holding assets in two power plants strung together" — but can't get gas to one plant, the marketer "simply move[s] the generation to the plant" where the gas is available, Schlesinger explained.

Under this scenario, "I have outrun a pipeline capacity bottleneck by appropriate use of generation assets." This type of scenario results in more creative and flexible deals and improved customer services, he added.

With the proliferation of energy marketers, "you can't be an active gas trader without being a successful power trader," said Schlesinger. "One commodity is no longer sufficient," he added.

Besides the technology constraints that limit the ability of marketers to carry out trades, there's also the issue of prices.

New pipelines will hold prices "in check through 2000," Schlesinger said. But in the near future when pipes such as the Sable Island project are completed, environmental and power demands will strengthen natural gas prices, he predicted.

—Victoria K. Green

Union Workers Declare Strike At New Jersey-Based Utility

For the second time in eight years, 300 members of the Utility Workers of America (UWA) Local 424 are on strike against Union, N.J.-based Elizabethtown Gas Co. because the company planned to outsource certain operational functions to contractors.

John Moriarty, a UWA official, said Elizabethtown "wanted to restructure the company with cross-training and workers assuming job duties that are overlapping each other."

Elizabethtown is seeking to separate its appliance repair functions from its distribution operations to allow the company to focus greater attention on this service. The company also said it wants to reduce the number of paid holidays and sick time.

The union contends that outsourcing will lead to serious safety concerns for the company.

Moriarty alleged that the company "has been letting a lot of their gas leaks go" but Elizabethtown officials denied those charges. According to the New Jersey Public Utility Board, the company has not been cited for any safety violations.

"The company is operating safely and reliably with management employees covering," said Elizabethtown spokesman Christopher Reardon.

Elizabethtown Gas — which serves about 240,000 customers in seven New Jersey counties — said it's fully prepared to operate the company for the duration of the strike. The company experienced a 24-day strike in 1990 and said its customers' service was never negatively impacted.

Labor experts note that outsourcing is on the rise in both the public and private sectors. Traditionally, most strikes have been over pay raises, but now workers are fighting for job security, those experts say.

"Outsourcing is a way for companies to decrease their costs and substitute lower paid workers for those who have decent pay and benefits," said Frank Parente, a labor economist with the AFL-CIO.

—Steve Parezo

Gas-Thirsty...

(continued from page 1)
the state's only existing interstate pipeline — will be expanding its now-filled system to accommodate new gas demand. The company laid out plans last week for a $350-million, 272,000-MMBtu/d expansion to meet growth derived mainly from new gas-fired power projects in the state.

FGT said that eight shippers have signed on to 20-year firm delivery commitments for the new capacity. Construction of the new pipeline would begin in March 2000, with

(continued on page 9)

SPOT PRICES ON INTRASTATE PIPELINE SYSTEMS
Delivered-to-Pipeline ($/MMBtu)
December 7, 1998

Pipeline	This Week	Weekly Change	Bid Week for Dec.
Louisiana Intrastates LIG, Bridgeline, LRC, Acadian	1.48	-0.53	2.08
Oklahoma Intrastates ONG, Transok, Enogex	1.48	-0.44	2.05
South Texas Intrastates HPL, Tejas, MidCon	1.56	-0.41	2.03
West Texas Intrastates Valero, Oasis, Delhi, Lonestar, Westar	1.38	-0.48	2.00

NOTES: (1) "Delivered-to-Pipeline" represents the volume-weighted average price paid for gas delivered into an intrastate transmission system. Prices include processing, gathering and transportation fees. (2) "This Week" is the average price of spot contracts with durations of 31 days or less. R = Revised.

(continued from page 8)
start-up expected in May 2001.

Whether the FGT expansion would compete directly with Transco's Buccaneer Pipeline project is undetermined; what is certain, however, is that Florida is in desperate need of greater access to gas supplies as new gas-fired power projects ramp up demand in the Sunshine State.

The Florida Public Service Commission estimates that the state will need an additional 1.5 Bcfd of gas in the next decade, primarily to fuel around 8,000 Mw of new electric generation capacity. Of that figure, 2,725 Mw in new gas-fired power capacity is expected for start-up by 2001.

Southeast Gas Demand to Rise

While Florida has the most immediate need for new gas supplies, the rest of the sunbelt may not be far behind.

Energy Ventures Analysis Inc. (EVA) sees Florida as the largest growth engine for power generation in the United States, with an annual rise of 3.7% expected through 2020. But the rest of the Southeast ranks second to Florida, with power demand growing at annual 2.7% clip over the same period.

While coal-fired production dominates the current generation mix of the sunbelt, EVA says combined cycle technology now gives gas an edge for new power projects in the region, especially for intermediate loads.

For its part, the Energy Information Administration predicts a healthy 33% increase in gas demand for the Southern Atlantic region through 2010.

"The sunbelt is clearly where the growth is," said Ross Willis, spokesman for Atlanta Gas Light Co. (AGL). Willis said that AGL is the fastest growing gas distributor in the country, adding between 30,000-50,000 customers a year to its service area.

Yet a problem endemic to much of the South is providing pipe infrastructure to provide access to what had been mostly rural communities. Despite their rapid economic development, Georgia has at least 15 counties without natural gas services, while in North Carolina about 72% of homes in the state go without gas.

"The problem we've got is there are not enough gas pipelines" said Fred D. Williams, a senior vice president at Southern Co. subsidiary Georgia Power Co. The lack of "pipeline capacity is starting to give us some concerns."

'We Need Another Interstate Pipe'

In some respects, the state which most mirrors Florida's predicament is North Carolina. Like Florida, the Tarheel State has only one interstate pipeline — in its case, Transco's pipe system — to provide gas to its growing service areas.

The potential danger of this single-supply reliance was exposed in August, when a compression station outage on FGT's mainline cut off gas supplies to virtually all of Florida.

"What we need here is another interstate pipeline," William Gilmore, an official at the North Carolina Utilities Commission, told *Natural Gas Week*.

According to Gilmore, North Carolina is caught in a squeeze: it is "way behind the eight ball" in setting up pipe infrastructure in the more rural eastern and western parts of the state. But Federal Energy Regulatory Commission bypass rules would allow industrials to tie-in directly to the Transco system, ensuring that rural regions would go without larger customers and remain high-cost service areas.

Voters in the state recently passed a $200 million bond issue to expand natural gas lines into poorer counties and combat this development imbalance (NGW, 11-9-98, p.6).

"We call this our 'Field of Dreams'," Gilmore said. "If we build it, we hope they [industrials] will come."

North Carolina's economy is booming. About 30,000 residents a year move to the state, with a corresponding rise in commercial industry. One gas distribution company, Piedmont Natural Gas Co., has identified 77 projects requiring significant investments in its service area.

Gilmore said that a Transco-financed pipeline, the 400-MMcfd Cardinal Extension Project, would satisfy most new gas demand in the immediate future.

—Andrew H. Ware

CITY GATE PRICES

December 7, 1998
($/MMBtu)

City	Bid Week for December	Bid Week for November
Austin, Texas		
Valero Transmission Co.	2.11	2.04
Boston, Mass.		
Algonquin Gas Transmission Co.	2.28	2.47
Chicago, Ill.		
Natural Gas Pipeline Co. of America	2.27	2.21
Denver, Colo.		
Colorado Interstate Gas Co.	2.19	2.18
Detroit, Mich.		
ANR Pipeline Co.	2.33	2.23
Panhandle Eastern Pipe Line Co.	2.34	2.22
Los Angeles, Calif.		
Southern California Natural Gas Co.	2.78	2.88
Minneapolis, Minn.		
Northern Natural Gas	2.23	2.13
Nashville, Tenn.		
Columbia Gulf Transmission Co.	2.12	2.07
Tennessee Gas Pipeline Co,.	2.10	2.02
New York, N.Y.		
Tennessee Gas Pipeline Co.	2.24	2.42
Texas Eastern Transmission Corp.	2.25	2.44
Transcontinental Gas Pipe Line Corp.	2.26	2.45
Philadelphia, Pa.		
Texas Eastern Transmission Corp.	2.23	2.40
Transcontinental Gas Pipe Line Corp.	2.24	2.41
Seattle Wash.		
Northwest Pipeline Corp.	2.21	2.05
Toronto, Ont.		
TransCanada Pipeline Co.,	1.85	2.04
Washington, D.C.		
Columbia Gas Transmission Corp.	2.22	2.36
Transcontinental Gas Pipe Line Corp.	2.22	2.38

NOTE: A city gate price represents the cost of gas at the point at which the local distribution company takes title to the gas, usually at the utility's gate station. The city gate price also can be the price to an end-user if the LDC is bypassed. Prices are reported on a weekly basis for the average price of contracts with durations of 31 days or less. R=Revised. Bid Week: These averages, updated the first issue of each month, reflect prices collected during the entire nomination period.

States Slowing Pace of March to Deregulation

The lack of progress of electricity restructuring legislation by Congress — created when the 105th Congress failed to make significant strides toward consensus (NGW, 10-12-98, p.10) — and recent challenges to restructuring in California and Massachusetts are prompting states to take a wait-and-see approach to setting new policies.

States are becoming increasingly concerned about the benefits of restructuring to consumers, recognizing that early warnings from utilities "are beginning to sink in with legislatures," said a Washington industry insider. Competition in some states has resulted in higher electricity costs, rather than the lower rates promised by many deregulation advocates. In addition, potential job losses and concern over rate hikes are among issues that have thwarted legislative action in states such as West Virginia and Ohio, and currently threaten Michigan's efforts to pass a restructuring bill.

Lawmakers in Michigan are debating whether to include a utility rate freeze and worker protections, but prospects for passing a bill this year are dwindling. "Their back is right up against the wall" and they're running out of time, said a spokesman for the Michigan Public Service Commission (PSC).

With the state's electric rates up to 15% higher than neighboring states, the "cost disparity" has resulted in "lost new projects and the jobs that go with them," said Doug Rothwell, CEO and department director of the Michigan Jobs Commission.

Although restructuring was upheld in California and Massachusetts after ballot initiatives threatened to undo existing laws (NGW, 11-9-98, p.10), many states remain concerned that customers won't see large enough rate cuts and will end up bailing out utilities with high stranded costs for power plants likely to be idled following restructuring.

"People are questioning late in the game what's being done with deregulation. Do customers get anything in return?" asked the industry source.

Electricity restructuring in West Virginia already has resulted in the loss of jobs, according to an economist at West Virginia University. Labor unions represented by the International Brotherhood of Electrical Workers fought "energetically against deregulation because they saw it as a tremendous source of job losses," he added.

"Ever since mergers started occurring like popcorn popping in a popper...lots of people have lost their jobs" to restructuring, said the Washington insider.

And those restructuring critics recently won after the West Virginia legislature shelved legislation until its next session.

Sinker Was Stranded Costs

Although concerns over job losses and rate hikes prevailed in many state debates, stranded-cost recovery emerged as the key sticking point in West Virginia, said Carl Irwin, division director of program development at the National Center for Coal and Energy.

Stranded costs are calculated by taking the total cost of utility generation minus the forecasted competitive market price. It's estimated that electric utilities in just 11 states will need more than $112 billion to bail out their failed investments, according to a study by the Safe Energy Communication Council (NGW, 10-5-98, p.11).

Irwin said the West Virginia PSC was charged with a "very challenging mandate" on which consensus was necessary, but the parties hunkered down and defeated the Senate proposal.

Although West Virginia regulators maintain stranded costs are negative $1 billion, the state's utilities say they're plus $1 billion, mostly from Public Utility Regulatory Policies Act projects, said another economist.

But he said utilities such as American Electric Power Co. (AEP) "won't fight over stranded costs because their generation facilities are worth way more than book value." AEP is "adamantly against divestiture," the economist added.

"Utilities were accused in the beginning [of the restructuring debate] of shying away from competition," said the Washington source, but now it's the states that are being coy.

—Victoria K. Green

More Power Hubs Likely to Develop

As the power market develops — both cash and futures — and transmission rules become more clearly defined, several more liquid cash trading hubs will develop alongside more futures contracts.

Several speakers at a recent power marketers conference sponsored by Institutional Investor Inc. said that as those rules shake out, and in light of June's power price spike in the Midwest, traders have to become more savvy and more regional transmission grids will bring more liquid spots.

Rusty Braziel, chairman of Altra Energy Technologies, said that the Commonwealth Edison Co. system, Electric Reliability Council of Texas, Pennsylvania-New Jersey-Maryland (PJM) interconnection, and New England Power Pool will become liquid hubs like the existing six: Cinergy Corp.'s system, California-Oregon border, Entergy Corp.'s system, Mid-Columbia, Palo Verde and Tennessee Valley Authority's system.

Braziel said that physical restraints of transmitting power, a factor that can only be corrected with infrastructure changes, is the main reason for the limited number of hubs.

As these markets develop, the Chicago Board of Trade (CBOT) continues to look at more futures contracts to provide hedging mechanisms for the highly volatile physical market.

Eric Meier, an advisory economist to the CBOT, said that the exchange — which is currently awaiting Commodity Futures Trading Commission approval for a PJM contract — is investigating bringing on a fourth contract.

He said that the June price spikes gave power marketers concerns about forward contracts due to counterparty defaults, but that organized exchanges — such as CBOT — are clearing corporations that back up trades.

—Scott C. Speaker

U.S. Public Power Producers Push for Nonprofit Transcos

WASHINGTON — Public power producers last week called not-for-profit independent transmission companies (transcos) "a superior alternative" to for-profit regional transmission organizations such as Independent System Operators (ISOs) and grid management companies that are currently under scrutiny by the Federal Energy Regulatory Commission (FERC) (NGW, 9-28-98, p.14).

FERC is advocating regional transmission entities as a way to ease transmission bottlenecks and manage electricity transactions. FERC has even questioned several potential mergers — such as the one between American Electric Power and Central & South West Corp. — because of their lack of participation in an ISO (NGW, 11-16-98, p.11).

As owners of 10% of the nation's transmission assets, public power producers — Salt River Project, New York Power Authority and 19 others located mostly in the U.S. Southeast and Southwest — are concerned that for-profit transcos "don't have an open governing structure" and may not represent the interests of all stakeholder groups, said Mark Crisson, CEO of Tacoma Public Utilities and chairman of the Large Public Power Council (LPPC).

"Any transmission solution should be truly independent of generation owners and other market participants," said Crisson. "Part of the problem with the transcos is they can charge rates based on market conditions...they have a monopoly on transmission."

LPPC advocates regional transmission groups and has proposed a set of principles that should be followed in developing any electric transmission system. "We're not pushing the LPPC transco model. What we're doing at this juncture in the debate is saying...let's take a look at some other possibilities and look at the pros and cons of all these models," Crisson said.

LPPC suggested that FERC consider not-for-profit regional transmission organizations as it sets rules for the restructured utility industry.

"In the case of gas...the reason that FERC's talking about other options for transmission is because they see that as a way to potentially address congestion or access issues that overall will lower the cost of gas [and] not raise it...if their proposal's going to raise the net cost to consumers, it's not going to be very popular and it's not going to go too far. And that's the problem we see with some of these private transco proposals on the power side."

AES Advances 700-Mw Gas-Fired Plant

ORLANDO, Fla. — Siemens Westinghouse Power Corp. last week won a $280 million contract from AES Ironwood Inc. to supply combustion and steam turbine generators for a new 700-Mw natural gas-fired power plant in Lebanon, Pa., near Harrisburg. The facility is expected to come online by 2001.

AES Ironwood, a subsidiary of Arlington, Va.-based AES Corp., will own and operate the facility, which will be powered by two 235-Mw combustion turbines and a 230-Mw steam turbine generator. While the plant burns mostly natural gas, it's also capable of burning oil and will rely on low-nitrogen oxide technologies to meet emission limits without water or steam injection when firing natural gas.

New 525-Mw Gas Plant Clears PSC

MADISON, Wisc. — Polsky Energy Corp. last week won preliminary approval from the Public Service Commission (PSC) of Wisconsin to build a 525-Mw gas-fired combustion turbine peaking facility in Dane County. The plant is expected to come online in June 2000.

The RockGen Energy Center plant is the first project to be authorized under legislation that requires Wisconsin's utilities to contract with merchant plants to ease the state's electric reliability problems.

The PSC is expected to issue a final order for the facility by the end of December.

Calpine/EMI to Build 265-Mw Plant

SAN JOSE, Calif. — Calpine Corp. and Dartmouth, Mass.-based Energy Management Inc. (EMI) last week teamed up to build a 265-Mw natural gas-fired merchant power plant in Rumford, Maine. Construction is expected to begin immediately and commercial operation, to be handled by EMI, is slated for mid-2000.

The Rumford plant represents the third project that Calpine and EMI are jointly constructing in New England. The companies also are building a 169-Mw plant in Dighton, Mass., and a 265-Mw facility in Tiverton, R.I. Much of the natural gas will be supplied by Aquila Energy Corp. (NGW, 7-27-98, p.11).

COMPARATIVE FUEL PRICES

(Cash Market)

December 7, 1998

APPALACHIA

Appalachian Pool Dlvd (Util)	Ohio/Big Sandy River Coal
	$27.25/ton
$1.71/MMBtu	$1.14/MMBtu

EAST COAST				GULF COAST					
Natural Gas	New York Harbor:			Natural Gas	Natural Gas	Gulf Coast:			
New York City Gate	Heating Oil—No. 2*	Residual 0.3%	Residual 1%	Texas Onshore Dlvd (Util)	Louisiana Onshore Dlvd (Util)	Heating Oil—No. 2*	Residual 0.7%	Residual 3%	WTI Cushing
	30.74¢/gal	$10.90/bbl	$9.87/bbl			28.55¢/gal	$11.00/bbl	$7.59/bbl	$11.21/bbl
$1.87/MMBtu	$2.22/MMBtu	$1.73/MMBtu	$1.57/MMBtu	$1.66/MMBtu	$1.52/MMBtu	$2.06/MMBtu	$1.75/MMBtu	$1.21/MMBtu	$1.93/MMBtu

NOTES: (1) Residual=Residual Fuel Oil, priced exclusive of taxes; (2) WTI=West Texas Intermediate crude oil; (3) % = % of sulfur content.
*Average sulfur content = 0.2%-0.5%.

SOURCES: Gas: *Natural Gas Week*; all prices volume-weighted. Oil: The weekly average of *The Oil Daily's* cash price postings.

Natural Gas and Electricity Futures Trading

Trading Dates: November 30 - December 4, 1998

New York Mercantile Exchange (Nymex) (Henry Hub)

	Monday Last/Volume	Tuesday Last/Volume	Wednesday Last/Volume	Thursday Last/Volume	Friday Last/Volume	Week's High/Low	Open Interest
January 1999	1.976/32155	1.958/37969	1.886/37990	1.959/50349	1.978 NA	2.060/1.811	56613
February 1999	1.999/16218	1.990/15847	1.931/11257	2.001/14093	2.024 NA	2.055/1.867	29183
March 1999	2.004/8927	1.988/8577	1.938/5421	1.998/6648	2.024 NA	2.050/1.885	26976
April 1999	2.005/4196	1.990/4886	1.948/3748	1.990/4250	2.010 NA	2.090/1.900	14935
May 1999	2.020/2626	2.003/2341	1.968/1983	2.000/2061	2.015 NA	2.090/1.930	11402
June 1999	2.035/2500	2.018/2729	1.988/1691	2.015/1934	2.025 NA	2.100/1.960	11536
July 1999	2.048/1436	2.030/1726	2.005/988	2.025/1031	2.030 NA	2.100/1.980	8472
August 1999	2.060/1045	2.042/1091	2.020/768	2.035/968	2.038 NA	2.120/2.000	7718
September 1999	2.072/1253	2.055/625	2.038/601	2.050/613	2.053 NA	2.130/2.010	6734
October 1999	2.125/946	2.110/704	2.097/672	2.100/1073	2.100 NA	2.170/2.060	5138
November 1999	2.265/423	2.252/337	2.240/310	2.240/666	2.240 NA	2.310/2.220	5779
December 1999	2.415/646	2.405/782	2.395/712	2.395/568	2.395 NA	2.455/2.375	6957
TOTAL VOLUME	**73,596**	**81,328**	**68,177**	**87,427**			**235,578**

Kansas City Board of Trade (KCBT)

	Monday Last/Volume	Tuesday Last/Volume	Wednesday Last/Volume	Thursday Last/Volume	Friday Last/Volume	Week's High/Low	Open Interest
January 1999	1.885/113	1.880/268	1.810/175	1.875/14	1.920/202	2.000/1.760	961
February 1999	1.890/2	1.875/12	1.810/25	1.885/0	1.930/48	1.950/1.810	463
March 1999	1.890/0	1.880/30	1.830/15	1.890/0	1.910/0	1.810/1.800	664
April 1999	1.890/0	1.890/0	1.850/0	1.890/21	1.910/1	1.890/1.890	89
May 1999	1.920/0	1.905/0	1.870/0	1.905/0	1.920/0	——	73
June 1999	1.980/0	1.920/0	1.900/0	1.905/0	1.920/0	——	56
July 1999	1.980/0	1.930/0	1.910/0	1.920/0	1.925/0	——	56
August 1999	2.000/0	1.955/0	1.935/0	1.945/0	1.950/0	——	58
September 1999	1.990/0	1.970/0	1.960/0	1.970/0	1.975/1	1.955/1.955	57
October 1999	2.010/0	2.015/0	2.010/0	2.020/0	2.010/1	2.010/2.010	57
November 1999	2.155/0	2.155/0	2.145/0	2.155/0	2.160/1	2.130/2.130	1
December 1999	2.260/0	2.260/0	2.250/0	2.260/0	2.265/0	——	1
TOTAL VOLUME	**115**	**310**	**215**	**35**	**254**		**2,536**

Nymex — California-Oregon Border

	Friday close	12-month strip
January 1999	25.78	27.73

CBOT — Tennessee Valley Authority

	Friday close	12-month strip
January 1999	—	NA

Nymex — Palo Verde, AZ

	Friday close	12-month strip
January 1999	26.15	33.28

CBOT — Commonwealth Edison Co.

	Friday close	12-month strip
January 1999	—	NA

Nymex — Entergy, LA

	Friday close	12-month strip
January 1999	25.90	NA

MGE — Twin Cities On-Peak

	Friday close	12-month strip
January 1999	30.00	NA

Nymex — Cinergy, OH

	Friday close	12-month strip
January 1999	27.50	NA

MGE — Twin Cities Off-Peak

	Friday close	12-month strip
January 1999	—	NA

NOTES: (1) Gas prices are in $/MMBtu; electricity prices in $/MwH. (2) Volume = Number of contracts signed. On days when no volumes are given the settlement committee determines a settlement price based on world events or trading during other months. (3) One contract = 10,000 MMBtu; one electricity contract = 736MwH. (4) Total Volume posted for Monday through Thursday is the total cleared volume. Total Volume posted for Friday is total estimated volume. (5) NT = No trading. (6) Last = Final daily settlement prices as established by Nymex and KCBT settlement committees. (7) Week's high/low: Settlement committee decides final settlement price based on last 2 minutes of trading. Final settlement price may be higher or lower than the highest or lowest reported sales during the day up to the last 2 minutes. (8) Open Interest = the number of contracts, not offset by sale or purchase by the same individual, in existence at the close of trading; in this table, the measuring point is the close of business on Fridays. SOURCES: New York Mercantile Exchange (Nymex); Kansas City Board of Trade (KCBT); Chicago Board of Trade; Minneapolis Grain Exchange.

Cash Market Hub Trading

($/MMBtu)

Henry Hub, La.

	Jan.	Feb.	March	April	May	June	July	August	Sept.	Oct.	Nov.	Dec.	Year
1990	2.39	1.90	1.55	1.49	1.47	1.47	1.41	1.36	1.44	1.69	2.10	2.11	1.70
1991	1.67	1.36	1.34	1.33	1.31	1.20	1.19	1.31	1.63	1.77	1.81	1.92	1.47
1992	1.28	1.21	1.28	1.47	1.59	1.56	1.75	1.97	2.33	2.42	2.24	2.16	1.80
1993	1.88	1.69	2.18	2.35	2.17	1.97	2.06	2.26	2.27	2.02	2.26	2.34	2.11
1994	2.34	2.71	2.21	2.04	1.92	1.90	1.96	1.66	1.49	1.51	1.58	1.72	1.86
1995	1.48	1.54	1.52	1.59	1.64	1.65	1.44	1.56	1.63	1.76	1.98	2.45	1.80
1996	2.92	4.41	3.00	2.71	2.21	2.43	2.57	2.12	1.84	2.27	2.82	3.78	2.76
1997	3.47	2.55	1.88	2.00	2.19	2.21	2.17	2.40	2.80	3.03	3.23	2.37	2.57
1998	2.10	2.17	2.23	2.45	2.18	2.14	2.25	1.90	1.91	1.93	2.06		

Current month: Dec. 7: $1.40 — Bid Week for Dec.: $2.11

Carthage, Texas

	Jan.	Feb.	March	April	May	June	July	August	Sept.	Oct.	Nov.	Dec.	Year
1994	2.19	2.49	2.02	1.94	1.84	1.78	1.88	1.62	1.43	1.45	1.55	1.61	1.75
1995	1.45	1.41	1.44	1.52	1.61	1.59	1.40	1.54	1.59	1.63	1.80	1.99	1.52
1996	1.98	2.27	2.38	2.33	2.14	2.33	2.51	2.13	1.79	2.04	2.73	3.75	2.37
1997	3.31	2.56	1.78	1.88	2.00	2.17	2.13	2.30	2.76	3.03	3.13	2.25	2.52
1998	2.07	2.10	2.18	2.40	2.15	2.11	2.23	1.88	1.90	1.89	2.00		

Current month: Dec. 7: $1.40 — Bid Week for 2.10

Katy, Texas

	Jan.	Feb.	March	April	May	June	July	August	Sept.	Oct.	Nov.	Dec.	Year
1993	1.83	1.69	2.08	2.26	2.04	1.92	2.05	2.23	2.13	1.97	2.31	2.14	2.07
1994	2.17	2.38	2.09	1.96	1.86	1.83	1.91	1.65	1.47	1.45	1.53	1.64	1.78
1995	1.40	1.39	1.42	1.49	1.57	1.55	1.38	1.50	1.57	1.62	1.75	1.90	1.51
1996	1.91	2.23	2.24	2.24	2.19	2.33	2.49	2.05	1.80	2.21	2.71	3.86	2.36
1997	3.59	2.55	1.82	1.94	2.11	2.16	2.12	2.42	2.80	2.94	3.15	2.28	2.56
1998	2.05	2.12	2.22	2.43	2.14	2.14	2.23	1.91	1.93	1.91	1.97		

Current month: Dec. 7: $1.38 — Bid Week for Dec.: $2.06

Blanco, N.M.

	Jan.	Feb.	March	April	May	June	July	August	Sept.	Oct.	Nov.	Dec.	Year
1994	1.84	2.17	1.92	1.75	1.56	1.50	1.57	1.57	1.33	1.31	1.49	1.59	1.59
1995	1.15	1.11	1.09	1.12	1.16	1.15	1.03	1.22	1.28	1.20	1.26	1.29	1.14
1996	1.21	1.22	1.17	1.15	1.13	1.27	1.66	1.91	1.55	1.76	2.61	3.46	1.68
1997	3.70	2.49	1.56	1.68	1.88	1.99	2.03	2.23	2.60	2.78	2.99	2.17	2.36
1998	2.00	1.92	2.07	2.16	1.96	1.70	1.89	1.80	1.70	1.71	1.94		

Current month: Dec. 7: $1.63 — Bid Week for Dec.: $1.98

Waha, Texas

	Jan.	Feb.	March	April	May	June	July	August	Sept.	Oct.	Nov.	Dec.	Year
1995	1.46	1.34	1.38	1.41	1.47	1.39	1.30	1.49	1.55	1.51	1.68	1.84	1.41
1996	1.98	2.07	2.39	2.34	2.07	2.12	2.22	2.04	1.71	2.19	2.74	3.85	2.31
1997	3.77	2.27	1.79	1.86	2.04	2.08	2.09	2.33	2.72	2.89	3.06	2.19	2.54
1998	2.02	2.02	2.15	2.30	2.09	2.03	2.21	1.87	1.85	1.87	1.99		

Current month: Dec. 7: $1.40 — Bid Week for Dec.: $1.99

NOTES: (1) This table reflects spot delivered-to-pipeline, volume-weighted average prices for natural gas bought and sold at specific trading hubs during the week prior to publication. (2) Prices include processing, gathering and transportation fees to the indicated hubs. R = Revised.

Natural Gas Rig Count

	Jan.	Feb.	March	April	May	June	July	August	Sept.	Oct.	Nov.	Dec.	Year
1995													
Total	748	713	665	672	679	674	723	745	765	760	772	763	723
Gas	411	375	331	336	335	352	399	399	413	412	430	427	385
% Gas	55.0	52.6	49.8	50.0	49.4	52.2	55.2	53.6	53.9	54.3	55.7	55.9	53.2
1996													
Total	709	700	716	741	764	771	784	811	811	836	848	852	779
Gas	405	411	418	446	467	469	487	488	503	499	482	489	464
% Gas	57.1	58.7	58.3	60.1	61.2	60.8	62.1	60.2	62.0	59.7	56.9	57.4	59.6
1997													
Total	822	849	897	901	924	976	969	993	1009	996	983	1013	943
Gas	478	492	518	526	541	577	584	581	614	602	625	650	565
% Gas	58.2	57.9	57.8	58.4	58.6	59.1	60.3	58.5	60.8	60.5	63.6	64.2	59.8
1998													
Total	993	974	932	886	855	854	816	792	774	734	688		
Gas	609	589	601	591	580	585	549	565	559	519	496		
% Gas	61.3	60.5	64.5	66.8	67.8	68.4	67.3	71.3	72.2	70.8	72.6		

1998 Dec. 4: 669/502/75.0%

SOURCE: Baker Hughes Inc.

Alliance Clears All Hurdles; Construction to Begin Soon

CALGARY — After an arduous and at times contentious confirmation process, the Alliance Pipeline finally cleared the last of its regulatory hurdles last week and is slated to start construction in January.

Canada's National Energy Board (NEB) approved the Canadian leg of the 1.325-Bcfd project last week. A few days later, Alliance received final approval from the Canadian government to allow the US$2.6 billion project to move forward.

"The vision is now a reality," said Alliance CEO Dennis Cornelson.

While giving its nod to the 1,600-mile system, however, the NEB attached 54 environmental, public safety and property protection conditions to its report.

Canadian environmental groups predictably said they would challenge the approval of the project. Alliance had also faced challenges from Alberta's petrochemical industry, which claimed that a shortage of natural gas liquids would result when the pipeline begins moving wet gas from British Columbia to Chicago.

The U.S. Federal Energy Regulatory Commission approved the U.S. leg of Alliance in September (NGW, 9-21-98, p.18). The Alliance Pipeline is expected to be in service by the fall of 2000.

Sempra Jumps into Nova Scotia

HALIFAX — Sempra Atlantic Gas Inc. said last week it plans to jump into the bidding to distribute natural gas in

(continued on page 15)

Canadian Markets

Yukon Territory to Make Debut In Canada Gas Supply Picture

Canada's Yukon Territory is long past its gold rush days, but it is preparing to open the way for a hoped-for rush of natural gas and oil exploration starting next year.

Canada's federal government recently finished handing over control of subsurface oil and gas in Yukon to the territorial government, after years of inactivity as the owner of what may be the largest remaining North American frontier region for energy exploration.

"In simple terms, we're the proud owners of oil and gas," said Brian Love, director of the energy resources branch of the Yukon government.

The natural gas reserve potential in Yukon is sheer speculation, according to Love, with only 71 oil and gas wells ever drilled in the territory.

The Yukon Territory has eight recognized sedimentary basins, five of which have never been drilled and several which have never even had seismic shot.

But the gas plays that have been tapped underscore the potential of the region. The Liard Plateau in the southeastern corner of Yukon — the only producing field in the territory — has two wells tied into the Westcoast Energy Inc. pipeline system producing 40-50 MMcfd each, triple the size of a respectable find in Alberta's Central Foothills.

"There's been a lot of interest among producers," Love told *Natural Gas Week*. The territory recently held a conference outlining its plans to promote gas and oil exploration, with about 80, mostly Alberta-based producers attending.

A royalty system and the regulations needed for sales of oil and gas rights will be in place in the first quarter of 1999, Love said, and sometime during next year the first licensing round will begin.

Yukon officials are consulting with the oil industry as they work on devising a competitive royalty regime and other regulations.

The concern for a "competitive" royalty system is a sign that Yukon realizes it will need to take account of the cost factors of geographic remoteness that could undercut the economics of projects.

Yukon's new ownership applies to gas and oil lying under 95% of the territory, public and private. The other 5% is owned by 14 Native American groups, which have agreed to harmonize their oil and gas regimes with that developed by the territorial government.

* * *

Rig Count: There were 267 rigs drilling for natural gas and oil in Western Canada as of Dec. 1, up from 248 reported the week before by the Canadian Association of Oilwell Drilling Contractors (CAODC).

During the same period a year ago, CAODC reported that 507 rigs were drilling in the region. A total of 581 rigs are available in the region, up from 579 reported in the previous week, CAODC said.

* * *

Working gas in all Canadian storage facilities decreased to 93.7% of capacity as of Nov. 27, down from 94.3% the week before, according to the most recent data available from the Canadian Gas Association (CGA).

Canadian storage facilities were 82.6% full a year ago.

A total of 486.4 Bcf of gas was in storage last week; capacity is 519 Bcf. There was 489.3 Bcf of stored gas the week before, the CGA said. Working gas levels in facilities west of Manitoba/Saskatchewan border decreased to 252.4 Bcf, down from 254.5 Bcf the week before; capacity is 276 Bcf.

Working gas levels east of the border decreased to 234 Bcf from 234.8 Bcf reported the previous week; capacity is 243.1 Bcf.

* * *

The composite spot import price this week is US$1.43/MMBtu for gas leaving Canada and entering the United States through six border crossing points.

Natural Gas Week's Dec. 8, 1997, average for Canadian exports was US$1.98/MMBtu.

Canada's average spot wellhead price is US$1.27/MMBtu; the price for the same week a year ago was US$1.18/MMBtu.

—Alan Kovski, Andrew H. Ware

(continued from page 14)
the burgeoning Nova Scotia market.

Sempra is the first of several companies expected to compete for the right to be the sole distributor in the province. The Nova Scotia government has given prospective bidders until Dec. 15 to file their notice of interest, with a final decision expected in June.

The new Nova Scotia gas system would be the largest start-up system in recent years, with steady gas supplies guaranteed after the Sable Island Project comes on stream.

The Nova Scotia government has already decided that major industrial gas buyers can directly tie-in to the Maritimes & Northeast Pipeline — which would distribute Sable gas southward to New England — but wants one distributor for the rest of the province.

Gulf Canada Continues Divestiture

DENVER — Gulf Canada Resources Ltd. signed a letter of intent with Equatorial Energy Inc. to sell C$70.5 million (US$46 million) of its oil and natural gas properties in Western Canada, continuing Gulf's divestiture program.

The properties being sold cover 340,000 net undeveloped acres in Alberta, southwestern Saskatchewan and northeastern British Columbia. Year-to-date production from these properties averaged 5,300 boe/d, with 55% of production represented by natural gas.

Canadian Pipe Returns Fall Again

CALGARY — Canada's National Energy Board (NEB) recently approved a 1999 rate-of-return on common equity (ROE) of 9.58% for eight major pipeline companies in the country.

As a result of the NEB's 1994 multi-pipeline cost of capital decision, the ROE has dropped from 11.25% in 1996 to 10.67% in 1997 and 10.21% in 1998.

—Andrew H. Ware

Canadian Price Report

($U.S. per MMBtu/$Can per Gigajoule)

	British Columbia Total Province	British Columbia Huntingdon/ Sumas Border	British Columbia Kingsgate/ Eastport Border	Alberta Total Province	Alberta AECO-C* Hub	Alberta Empress Border	Saskatchewan Total Province	Saskatchewan Monchy Border	Manitoba Emerson Border	Ontario Toronto City Gate	Ontario Niagara Border
	Spot	Spot	Spot	Spot/Con.	Spot/Con.	Spot/Con.	Spot	Spot	Spot/Con.	Spot	Spot/Con.
1997 AVERAGE											
Wellhead U.S. $	1.50			1.25/1.22			2.03				
Canadian $	1.92			1.60/1.57			2.56				
Delivered to Pipe U.S.$	1.58	1.58	1.58	1.33/1.30	1.36/1.33	1.44/1.37	1.41	2.02	2.19/1.85	2.70	2.71/1.87
Canadian $	2.02	2.02	2.03	1.70/1.67	1.74/1.70	1.84/1.76	1.80	2.60	2.81/2.38	3.46	3.47/2.40
SEPTEMBER 1997											
Wellhead U.S. $	1.27			1.18/1.22			1.87				
Canadian $	1.63			1.52/1.57			2.41				
Delivered to Pipe U.S.$	1.35	1.25	1.44	1.26/1.30	1.14/1.34	1.18/1.37	1.95	2.21	1.71/1.90	2.79	2.80/1.86
Canadian $	1.73	1.61	1.86	1.62/1.67	1.47/1.73	1.51/1.76	2.51	2.84	2.20/2.44	3.60	3.60/2.40
FIRST QUARTER 1998											
Wellhead U.S. $	1.51			1.02/1.18			1.03				
Canadian $	2.01			1.36/1.57			1.37				
Delivered to Pipe U.S.$	1.58	1.60	1.58	1.10/1.25	1.19/1.30	1.34/1.32	1.10	1.74	1.89/1.84	2.31	2.34/1.81
Canadian $	2.11	2.12	2.09	1.46/1.67	1.59/1.73	1.78/1.76	1.47	2.32	2.52/2.44	3.08	3.10/2.40
SECOND QUARTER 1998											
Wellhead U.S. $	1.49			1.30/1.18			1.30				
Canadian $	1.99			1.73/1.57			1.74				
Delivered to Pipe U.S.$	1.57	1.54	1.60	1.37/1.25	1.46/1.30	1.59/1.32	1.38	1.83	1.73/1.83	2.38	2.40/1.80
Canadian $	2.09	2.05	2.13	1.83/1.67	1.95/1.73	2.12/1.76	1.84	2.44	2.31/2.44	3.18	3.20/2.40
THIRD QUARTER 1998											
Wellhead U.S. $	1.43			1.21/1.18			1.21				
Canadian $	2.03			1.71/1.57			1.72				
Delivered to Pipe U.S.$	1.50	1.52	1.49	1.28/1.25	1.37/1.30	1.40/1.32	1.28	1.49	1.44/1.83	1.94	1.97/1.80
Canadian $	2.13	2.15	2.11	1.81/1.67	1.93/1.73	1.98/1.76	1.82	2.10	2.04/2.44	2.75	2.78/2.40
OCTOBER 1998											
Wellhead U.S. $	1.71			1.57/1.11			1.57				
Canadian $	2.43			2.23/1.57			2.23				
Delivered to Pipe U.S.$	1.76	1.76	1.76	1.62/1.16	1.70/1.20	1.77/1.23	1.62	1.52	1.78/1.70	2.05	2.08/1.67
Canadian $	2.53	2.53	2.53	2.33/1.67	2.44/1.73	2.55/1.76	2.33	2.18	2.56/2.44	2.95	2.99/2.40
NOVEMBER 1998											
Wellhead U.S. $	1.78			1.58/1.09			1.58				
Canadian $	2.56			2.28/1.57			2.27				
Delivered to Pipe U.S.$	1.85	1.86	1.84	1.65/1.16	1.74/1.20	1.82/1.23	1.65	1.63	1.91/1.70	2.18	2.21/1.67
Canadian $	2.66	2.68	2.65	2.38/1.67	2.50/1.73	2.61/1.76	2.37	2.35	2.74/2.44	3.13	3.17/2.40
DECEMBER 7, 1998											
Wellhead U.S. $	1.56			1.13/1.09			1.13				
Canadian $	2.25			1.62/1.57			1.62				
Delivered to Pipe U.S.$	1.63	1.63	1.64	1.20/1.16	1.28/1.20	1.30/1.23	1.20	0.93	1.32/1.70	1.43	1.43/1.67
Canadian $	2.35	2.34	2.35	1.72/1.67	1.84/1.73	1.87/1.76	1.72	1.34	1.90/2.44	2.05	2.06/2.40

NOTES: (1) /are in $U.S./MMBtu and $Canadian/Gigajoule. /conversions are done weekly. Source: Federal Reserve Bank of New York. (2) /refers to contract /durations of less /12 months. (3) Contract refers to terms /1 year or more. (4) /prices represent volume-weighted averages of the most recently reported gas sales contracts and price renegotiations. (5) Divd. to Pipe" means Delivered to Pipe" and refers to TransCanada PipeLines Ltd. in all provinces except Alberta (Nova Corp. of Alberta) and British Columbia (Westcoast Energy Inc.). *Denotes pricing at Alberta Energy Co.'s marketing hub in southeastern Alberta. R = Revised.

AEP Unit Completes Purchase Of Equitable Midstream Assets

AEP Resources Inc., a wholly owned subsidiary of **American Electric Power Co.**, has completed its purchase of the midstream natural gas operations of **Equitable Resources Inc.** for $320 million plus working capital.

The midstream operations include fully integrated gathering, processing and storage operations in Louisiana and an energy trading and marketing business based in Houston.

Assets include **Louisiana Intrastate Gas Co. L.L.C.**, a 2,000-mile intrastate pipeline system; four natural gas processing plants that straddle the pipeline, plus a fifth plant currently under construction and Jefferson Island storage facilities, including an existing salt dome storage cavern and a second cavern under construction, both directly connected to the Henry Hub in Louisiana.

The pipeline and storage facilities are interconnected to 12 interstate and 24 intrastate pipelines running to the major consumption markets in the Northeast, Midwest and Southeast.

Southeast:

The Williams Companies Inc. is planning an open season in early January 1999 for the Buccaneer Pipeline, which is projected to run from Station 82 on the **Williams Gas Pipeline-Transcontinental Gas Pipe Line Corp.** (Transco) near Mobile Bay, Ala., cross the northeastern Gulf of Mexico and come onshore near Tampa, Fla.

The project's target market is electric power generators, both utility-owned and independent.

Potential costs of the project were not disclosed, but based on industry data the offshore segment alone of a 500-MMcfd line could cost in the range of $600 million (NGW, 10-26-98, p.5).

Buccaneer's capacity and final routing will be determined after the open season. Once the routing is determined, the companies plan to file a proposal at the Federal Energy Regulatory Commission in early 1999.

Canada:

Union Gas Storage & Transportation Services of Chatham, Ontario, said it is holding three open seasons until Feb. 16 to determine shipper interest in long-term firm

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SPOT PRICES ON INTERSTATE PIPELINE SYSTEMS — PART 1

Delivered-to-Pipeline ($/MMBtu)
December 7, 1998

Pipeline	This Week	Weekly Change	Bid Week for Dec	Bid Week for Nov	1997 Avg.	Dec 1997	Jan 1998	Feb 1998	Mar 1998	Apr 1998	May 1998	Jun 1998	Jul 1998	Aug 1998	Sep 1998	Oct 1998	Nov 1998
ANR Pipeline Co.																	
Southeast: Patterson, La.	1.30	-0.64	2.07	1.88	2.46	2.28	2.10	2.08	2.17	2.32	2.15	2.06	2.19	1.82	1.82	1.92	2.04
Southwest: Laverne Station, Okla.	1.70	-0.20	2.07	1.98	2.31	2.27	2.10	2.06	2.18	2.31	2.12	2.03	2.17	1.82	1.79	1.90	1.99
CNG Transmission Co.																	
North	1.86	-0.31	2.36	2.23	2.67	2.64	2.25	2.28	2.42	2.62	2.38	2.31	2.42	2.07	2.09	2.21	2.28
South	1.58	-0.62	2.34	2.22	2.81	2.58	2.34	2.28	2.41	2.64	2.38	2.28	2.42	2.06	2.06	2.16	2.24
Colorado Interstate Gas Co.																	
Kanda, Wyo.	1.40	-0.39	1.94	1.93	2.12	2.04	2.00	1.77	1.95	2.05	1.86	1.55	1.70	1.71	1.60	1.70	1.88
Columbia Gas Transmission Corp.																	
Maumee, Ohio	1.59	-0.55	2.29	2.19	2.60	2.48	2.19	2.20	2.30	2.53	2.31	2.19	2.37	1.99	1.98	2.16	2.28
Broad Run, W.Va.	1.60	-0.55	2.30	2.18	2.62	2.48	2.20	2.20	2.31	2.54	2.30	2.18	2.36	1.98	1.98	2.16	2.27
Appalachian Pooled	1.64	-0.55	2.34	2.25	2.72	2.44	2.23	2.27	2.36	2.59	2.35	2.23	2.40	2.03	2.00	2.16	2.34
Columbia Gulf Transmission Co.																	
Erath, La.	1.47	-0.53	2.08	2.02	2.51	2.36	2.14	2.14	2.20	2.39	2.17	2.11	2.24	1.87	1.89	1.95	2.05
Rayne, La.	1.49	-0.56	2.15	2.11	2.43	2.39	2.12	2.18	2.23	2.43	2.22	2.17	2.29	1.89	1.96	1.99	2.08
Texaco Henry Plant, La.	1.40	-0.62	2.11	2.01	2.57	2.37	2.10	2.17	2.23	2.45	2.18	2.14	2.25	1.90	1.91	1.96	2.06
El Paso Natural Gas Co.																	
Permian: Waha, Texas	1.50	-0.36	2.00	1.93	2.41	2.16	2.00	1.97	2.10	2.25	2.04	1.94	2.18	1.85	1.82	1.83	2.00
San Juan: Ignacio, Colo.	1.55	-0.32	1.98	1.87	2.37	2.17	2.00	1.94	2.08	2.18	1.95	1.70	1.90	1.79	1.72	1.72	1.94
California border: Topock Station	1.93	-0.32	2.28	2.33	2.52	2.28	2.29	2.17	2.35	2.48	2.23	2.05	2.40	2.29	2.10	2.19	2.42
Florida Gas Transmission Co.																	
Mustang Island (Tivoli) (Zone 1)	1.53	-0.44	2.05	1.96	2.49	2.31	2.07	2.16	2.19	2.39	2.14	2.10	2.24	1.86	1.96	1.94	1.99
Vermilion Parish, La. (Zone 2)	1.52	-0.52	1.99	2.11	2.50	2.37	2.15	2.19	2.22	2.43	2.19	2.17	2.29	1.92	1.91	1.98	2.08
St. Helena Parish, La. (Zone 3)	1.53	-0.48	2.09	1.90	2.56	2.37	2.17	2.19	2.22	2.40	2.21	2.15	2.26	1.88	1.92	1.97	2.05
Iroquois Gas Transmission System																	
Waddington, N.Y.	1.89	-0.27	2.44	2.25	2.83	2.65	2.23	2.32	2.41	2.56	2.31	2.26	2.50	2.05	2.09	2.20	2.29
Kern River Gas Transmission Co.																	
Opal, Wyo.	1.42	-0.37	2.02	2.00	2.19	2.07	2.00	1.76	1.94	2.13	1.87	1.52	1.72	1.76	1.68	1.77	1.91
Wheeler Ridge, Calif. (Kern Cty./SoCal Jct.)	1.96	-0.32	2.22	2.28	2.38	2.27	2.28	2.15	2.35	2.47	2.26	2.09	2.41	2.29	2.16	2.15	2.40
Koch Gateway Pipeline Co.																	
Louisiana	1.33	-0.59	2.12	1.96	2.39	2.28	2.11	2.13	2.19	2.29	2.14	2.05	2.22	1.81	1.66	1.89	1.95
Texas	1.69	-0.22	2.04	1.89	2.42	2.22	1.99	1.99	2.13	2.22	2.08	2.03	2.15	1.78	1.70	1.88	1.94
Natural Gas Pipeline Co. of America																	
Lake Arthur, La.	1.39	-0.57	2.06	2.05	2.41	2.24	2.09	2.12	2.19	2.39	2.15	2.11	2.23	1.86	1.89	1.94	2.01
Forgan, Okla.	1.69	-0.19	2.06	1.97	2.48	2.21	2.07	2.08	2.16	2.34	2.11	2.04	2.18	1.82	1.81	1.86	1.96
South Texas (Agua Dulce)	1.41	-0.48	1.91	1.90	2.44	2.25	2.05	2.10	2.17	2.37	2.14	2.08	2.21	1.82	1.85	1.89	2.01
TexOk (Midwest Zone)	1.46	-0.46	2.03	1.98	2.53	2.27	2.06	2.11	2.19	2.37	2.16	2.10	2.22	1.86	1.89	1.92	2.00
NorAm																	
East	1.69	-0.21	2.08	1.97	2.44	2.28	2.09	2.10	2.17	2.35	2.14	2.09	2.20	1.85	1.87	1.93	1.98
West	1.44	-0.41	2.03	1.92	2.38	2.26	2.09	2.05	2.16	2.33	2.14	2.04	2.17	1.83	1.75	1.91	1.94
Northern Natural Gas Co.																	
Custer County, Okla.	1.60	-0.19	1.95	1.80	2.36	2.19	2.01	1.92	2.08	2.21	2.01	1.96	2.16	1.83	1.77	1.86	1.90
Ventura, Iowa	1.55	-0.34	2.13	2.03	2.32	2.26	2.12	2.06	2.23	2.32	2.12	2.04	2.19	1.83	1.75	1.93	2.06

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natural gas transportation that would be available next year through 2001.

Results of the open seasons will be used as the basis for an expansion application to the **Ontario Energy Board** in 1999, Union Gas said.

On the downstream side, Union Gas is soliciting bids on firm capacity from its Dawn storage facility to Parkway, Ontario and Kirkwall, Ontario. Union Gas is soliciting bids between its two St. Clair River points and Dawn.

The company is also accepting bids on firm transportation from its interconnection with Panhandle Eastern Pipe Line Co. at Ojibway to Dawn.

"The demand for gas in the U.S. Northeast is growing at a rate faster than anywhere in the U.S.," said Garry Black, general manager of storage and transportation services for Union Gas.

The Dawn facility has a working gas capacity of 126 Bcf and a deliverability of 2 Bcfd.

Southwest:

Transwestern Pipeline Co. said it is holding an open season until Dec. 18 to determine shipper interest for 140,000 Dt/d of additional mainline natural gas capacity from Thoreau to the California border.

The additional capacity would result from adding a new compressor station near Gallup, N.M., on the mainline between the existing compressor stations No. 4 and No. 5.

The project, which would cost between $15 million and $20 million, is estimated to be in service on Nov. 1, 1999.

Northeast:

National Energy Choice said its Boston-based energy aggregation company **NEChoice L.L.C.**, is offering low-cost natural gas to commercial, industrial and municipal consumers in Massachusetts and Rhode Island.

The program offers savings of 10%-25% off the natural gas supply portion of gas bills, the company said. National Energy chose **e prime** to provide natural gas to its customers from a field of 50 competitors.

The NEChoice program offers contract terms of either one or two years, and customers can opt for either fixed percentage savings or fixed price contracts.

The deadline for participation in the program is Feb. 19.

—Steve Parezo

SPOT PRICES ON INTERSTATE PIPELINE SYSTEMS — PART 2

Delivered-to-Pipeline ($/MMBtu)
December 7, 1998

Pipeline	This Week	Weekly Change	Bid Week for Dec	Bid Week for Nov	1997 Avg.	Dec 1997	Jan 1998	Feb 1998	Mar 1998	Apr 1998	May 1998	Jun 1998	Jul 1998	Aug 1998	Sep 1998	Oct 1998	Nov 1998
Northwest Pipeline Corp.																	
Sumas, Wash.	1.63	-0.20	2.15	1.99	1.64	1.72	2.04	1.32	1.32	1.74	1.51	1.37	1.48	1.58	1.55	1.75	1.89
Green River, Wyo.	1.55	-0.22	2.02	2.03	1.99	2.05	1.98	1.77	1.94	2.10	1.88	1.53	1.71	1.76	1.69	1.78	1.91
Pacific Gas Transmission Co.																	
Kingsgate	1.64	-0.15	2.00	2.00	1.70	1.53	1.69	1.43	1.60	1.84	1.50	1.41	1.60	1.53	1.48	1.78	1.80
Stanfield	1.61	-0.22	2.06	2.06	1.83	1.81	2.01	1.72	1.88	2.08	1.73	1.50	1.73	1.77	1.68	1.79	1.95
Malin, Ore.	1.77	-0.28	2.16	2.24	1.99	2.02	2.10	1.79	2.00	2.19	1.86	1.69	1.95	2.06	1.87	1.99	2.27
Panhandle Eastern Pipe Line Co.																	
Kansas/Oklahoma Field Zone	1.66	-0.24	2.07	1.96	2.44	2.24	2.07	2.05	2.17	2.34	2.12	2.02	2.16	1.81	1.77	1.89	2.01
Questar Pipeline Co.																	
Kanda, Wyo.	1.31	-0.42	1.96	1.91	2.03	2.03	1.99	1.73	1.91	1.98	1.88	1.49	1.67	1.73	1.60	1.69	1.86
Southern Natural Gas Co.																	
St. Mary Parish, La.	1.56	-0.46	2.10	2.01	2.54	2.37	2.19	2.14	2.22	2.38	2.17	2.14	2.27	1.90	1.82	1.99	2.04
Tennessee Gas Pipeline Co.																	
Zone 1: South Louisiana	1.37	-0.58	2.05	1.97	2.44	2.33	2.11	2.10	2.17	2.37	2.15	2.07	2.19	1.84	1.82	1.94	2.04
Zone 0: South Texas	1.43	-0.49	1.96	1.89	2.43	2.22	2.06	2.08	2.16	2.36	2.12	2.04	2.17	1.83	1.82	1.89	2.02
Texas Eastern Transmission Corp.																	
East Texas	1.58	-0.34	2.02	1.92	2.41	2.26	2.07	2.08	2.15	2.38	2.16	2.05	2.20	1.84	1.84	1.93	2.02
South Texas	1.61	-0.34	1.98	1.88	2.47	2.25	2.06	2.04	2.14	2.35	2.13	2.05	2.20	1.81	1.83	1.90	2.00
West Louisiana	1.44	-0.51	2.06	1.98	2.47	2.31	2.11	2.10	2.16	2.38	2.16	2.06	2.20	1.85	1.89	1.93	2.01
East Louisiana	1.46	-0.50	2.07	2.00	2.55	2.33	2.16	2.11	2.17	2.38	2.17	2.09	2.23	1.87	1.87	1.92	2.03
Market Zone 1: Mississippi	1.48	-0.54	2.24	2.03	2.57	2.48	2.47	2.21	2.30	2.47	2.25	2.16	2.26	1.91	1.94	2.02	2.12
Texas Gas Transmission Corp.																	
Zone 1: North Louisiana	1.75	-0.28	2.08	1.89	2.46	2.35	2.13	2.13	2.24	2.45	2.20	2.16	2.28	1.86	1.91	1.96	2.07
Zone SL: South Louisiana	1.42	-0.58	2.10	2.00	2.59	2.38	2.15	2.13	2.22	2.40	2.18	2.13	2.25	1.87	1.94	1.97	2.07
Transcontinental Gas Pipe Line Corp.																	
Station #30 (Wharton County, Texas/Zone 1)	1.90	-0.06	2.03	1.90	2.45	2.26	2.09	2.15	2.16	2.37	2.16	2.07	2.26	1.86	1.71	1.91	2.03
Station #45 (Texas-La. border/Zone 2)	1.70	-0.28	2.11	1.98	2.47	2.32	2.12	2.14	2.20	2.42	2.19	2.11	2.25	1.89	1.92	1.96	2.04
Stations #50, 62, 65 (South La./Zone 3)	1.47	-0.55	2.12	2.03	2.64	2.43	2.15	2.18	2.23	2.45	2.21	2.14	2.27	1.90	1.91	2.01	2.09
Holmesville, Miss.	1.63	-0.40	2.18	2.05	2.76	2.40	2.17	2.18	2.24	2.44	2.22	2.15	2.27	1.93	1.96	2.03	2.09
Transwestern Pipeline Co.																	
East of Thoreau	1.54	-0.36	2.00	1.99	2.41	2.15	2.03	2.03	2.13	2.30	2.07	1.93	2.18	1.89	1.72	1.87	2.00
California border: Mohave County, Ariz.	1.94	-0.31	2.28	2.33	2.47	2.28	2.29	2.17	2.35	2.49	2.24	2.05	2.40	2.29	2.11	2.20	2.42
Trunkline Gas Co.																	
East La.	1.29	-0.65	2.02	2.16	2.41	2.29	2.09	2.11	2.18	2.36	2.15	2.10	2.19	1.82	1.89	1.93	2.01
Bee County, TX	1.57	-0.40	1.85	2.13	2.46	2.26	2.07	2.05	2.15	2.30	2.16	2.09	2.22	1.84	1.76	1.88	2.07
West La.	1.46	-0.51	2.05	2.13	2.55	2.37	2.11	2.16	2.22	2.43	2.18	2.13	2.25	1.88	1.90	1.96	2.06
Williams Natural Gas Co.																	
Mainline, Kan./Okla.	1.57	-0.31	2.07	1.93	2.39	2.24	2.03	2.04	2.17	2.34	2.11	2.08	2.19	1.85	1.76	1.86	2.00

NOTES: (1) Average price paid for spot contracts with durations of 31 days or less. Prices include wellhead price plus processing, gathering and transportation fees. Prices are volume-weighted and reflect deals done the week before publication, regardless of time of delivery. (2) A dash (—) means insufficient price quotes for meaningful average. (3) Bid Week: These averages, updated the first issue of each month, reflect prices collected during entire nomination period. R = Revised.

Pairing...

(continued from page 1)
and Exxon's position in the Netherlands alone gives it substantial influence in the European market. The combination's future growth, however, appears to be centered in the Asia-Pacific region, where it has the potential to dominate the power and natural gas businesses in the coming decades.

Whether the technology is long-distance pipelines, liquefied natural gas (LNG), or natural gas-to-liquids (GTL) conversion, no other company matches the combined gas capabilities of Exxon and Mobil.

Exxon is working with Japanese steel manufacturers to develop higher-strength, thinner-walled natural gas line pipe. The goal is to reduce the cost of long-distance gas pipelines and make pipeline projects overall more economically feasible.

Mobil is an acknowledged leader in LNG. It is a major player in Indonesia's and Qatar's LNG businesses and longer-term aims in Australia. Besides its position in conventional LNG plants, the company is working aggressively to develop barge-mounted LNG liquefaction facilities and receiving terminals. The goal is to lower the economic feasibility threshold for LNG projects.

Exxon is looking at a number of potential applications for its proprietary GTL technology that converts natural gas into environmentally friendly grades of middle distillates. These run the gamut from mega-ventures of 100,000 b/d or more in Qatar and Alaska to barge-mounted units that could be used for offshore installations.

The two companies' assets in Asia share a comparable magnitude. Among them are Mobil's Arun gas field and LNG venture in Indonesia, as well as its recently acquired Australian gas production and LNG operations; Exxon's massive, but unexploited, gas reserves offshore Sakhalin Island and on Alaska's North Slope; Exxon's enormous gas position in Malaysia; and their joint holdings in the proposed Natuna gas development project in Indonesia.

Exxon Big Player in Global Power

Exxon also is a "power" in electricity. It has interests in 7,800 Mw of power generation capacity serving Hong Kong, making it the largest independent power producer in Asia. Some of the plants are fueled by coal, but newer facilities are gas-fired.

Extending their presence further, both companies have active involvement in various markets, even in countries where they do not have upstream gas assets. For example, Mobil has contracts to sell LNG to Korea, Japan and India. Exxon is participating in a study that could lead to a pipeline project from Sakhalin to Japan, China and Korea.

If the two companies have a cultural conflict over natural gas strategy, it is Exxon's support of pipelines against Mobil's preference for LNG. Indonesia's Natuna field is an example. Mobil took a position in the project to gain additional reserves to back the Arun LNG project. Exxon is more interested in piping the gas to power plants in Indonesia and elsewhere in Southeast Asia.

Malaysia is another illustration. Exxon produces more than 550 MMcfd of gas there, all transported by pipe, and projects in development also involve pipeline deliveries. By comparison, the Royal Dutch/Shell Group fuels a large LNG project with its gas.

In Europe, Exxon and Mobil are a formidable presence. Exxon produced 70% of the duo's 4.28-Bcfd net European output last year, and it has a similar proportion of their combined 11.75-Tcf-plus proven European reserves. On both a market-share and a volumetric basis, Exxon is bigger in European gas than it is in North America.

The largest single asset is Exxon's share of the giant Groningen field in the Netherlands, which it holds jointly with Shell, and its 25% stake in the Dutch gas marketer Gasunie, also 25% owned by Shell. The Dutch government has the remaining 50%. Exxon and Shell have a number of upstream arrangements in Europe whose future and Mobil's role in them have yet to be disclosed. European Union regulators may have an influential say in the outcome.

Gas Reserves, Production in Exxon-Mobil Deal

(figures for 1997)

	Exxon	Mobil	Combined
Natural Gas Production (MMcfd)			
U.S.	2,062	1,160	3,222
Canada	203	397	600
Europe, other	3,038	1,427	4,465
Indonesia	—	1,571	1,571
Asia-Pacific	1,036	—	1,036
Total	6,339	4,555	10,894
Natural Gas Reserves (Bcf)			
U.S.	9,689	3,931	13,620
Europe	23,494	4,299	27,793
Asia-Pacific	7,223	3,088	10,311
Middle East, Canada, Others	1,723	5,638	7,361
Total	42,129	16,956	59,085

all data from annual reports

Mobil and Exxon have diverged on gas marketing strategies in Europe just as they have in North America. Mobil is one of the leading industrial gas suppliers in the United Kingdom (UK), while Exxon sold its UK gas sales business to Shell. At the same time, Exxon has more investments in midstream gas operations in Europe than in the United States. The Gasunie position is one example, along with Exxon's participation in Germany's Ruhrgas.

How their North American gas operations will be consolidated hasn't been revealed, either. Collectively, Exxon and Mobil produce 3.7 Bcfd in the United States and Canada, well ahead of Amoco Corp., the previous leader at 2.85 Bcfd. Since British Petroleum plc is a relatively small North American gas operator, Exxon Mobil will retain the top spot after completion of the BP-Amoco merger.

Previously, the two companies followed diametrically opposite strategies for selling their output. Mobil built up a large marketing program in the early 1990s, handling its own and third-party production. In 1996, Mobil formed a joint venture with a predecessor to Duke Energy Trading, where its production represents about 20% of Duke's total supply.

Exxon has chosen to go its own way, marketing only equi-